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(54) Title: NMR APPARATUS AND METHODS FOR MEASURING VOLUMES OF HYDROCARBON GAS AND OIL
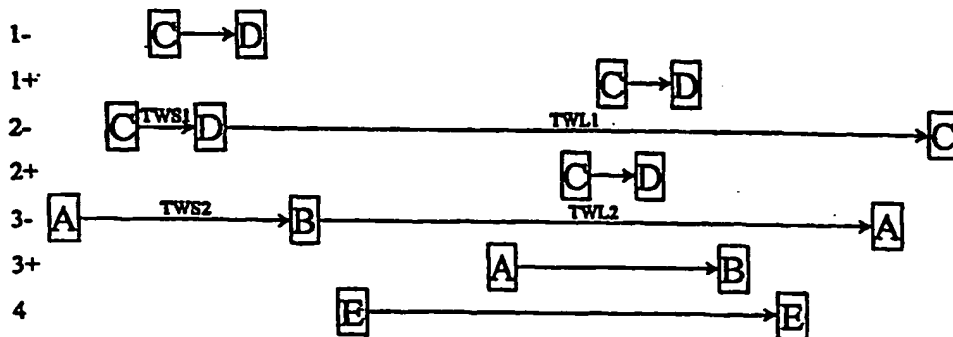
(57) Abstract: A multifrequency method and apparatus for NMR logging. The apparatus and method uses a triple-wait-time (TWS1, TWS2, TWL1) NMR sequence to determine gas and light-oil filled porosity over a broad range of reservoir conditions. A set of conditions is derived for the selection of optimum acquisition parameters. The conditions are developed to aid in the selection of wait time combinations.

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NMR APPARATUS AND METHODS FOR MEASURING VOLUMES OF HYDROCARBON GAS AND OIL

Field of the Invention

The present invention relates to borehole measurements and more particularly to a system and method for detecting the presence and estimating the quantity of gaseous and liquid hydrocarbons using nuclear magnetic resonance.

Background

Various methods exist for performing measurements of petrophysical parameters in a geologic formation. Nuclear magnetic resonance (NMR) logging, which is the focus of this invention, is among the best methods that have been developed for a rapid determination of such parameters, which include formation porosity, composition of the formation fluid, the quantity of movable fluid and permeability, among others. NMR measurements are environmentally safe and are essentially unaffected by matrix mineralogy, because NMR signals from the matrix decay too quickly to be detected by the current generation NMR logging tools. Thus, unlike conventional neutron, density, sonic, and resistivity logs, NMR logs provide information only on formation fluids. Importantly, however, NMR tools are capable of directly measuring rock porosity filled with the fluids. Even more important is the unique capability of NMR tools, such as NUMAR Corporation's MRIL® tool to distinguish among different fluid types, in particular, clay-bound water, capillary-bound water, movable water, gas, light oil, medium oil, and heavy oil by applying different sets of user-adjusted measurement parameters. (MRIL is a mark of NUMAR Corporation, a Halliburton company). This ability to detect the presence and estimate the volumes of different types of fluids is becoming one of the main concerns in the examination of the petrophysical properties of a geologic formation.

To better appreciate how NMR logging can be used for fluid signal separation and estimating fluid volumes, it is helpful to briefly examine the type of parameters that can be measured using NMR techniques. It is well known that

when an assembly of magnetic moments, such as those of hydrogen nuclei, are exposed in a NMR measurement to a static magnetic field they tend to align along the direction of the magnetic field, resulting in bulk magnetization. The rate at which equilibrium is established in such bulk magnetization upon provision of a static magnetic field is characterized by the parameter T_1, known as the spin-

5   lattice relaxation time. Another related and frequently used NMR logging parameter is the spin-spin relaxation time T_2 (also known as transverse relaxation time), which relaxation is the loss of transverse magnetization due to non-homogeneities varying in time in the local magnetic field over the sensing volume of the logging tool. Both relaxation times provide information about the

10   formation porosity, the composition and quantity of the formation fluid, and others.

Another measurement parameter obtained in NMR logging is the diffusion of fluids in the formation. Generally, diffusion refers to the motion of atoms in a gaseous or liquid state due to their thermal energy. Self-diffusion is

15   inversely related to the viscosity of the fluid, which is a parameter of considerable importance in borehole surveys. In a uniform magnetic field, diffusion has little effect on the decay rate of the measured NMR echoes. In a gradient magnetic field, however, diffusion causes atoms to move from their original positions to new ones, which moves also cause these atoms to acquire different phase shifts

20   compared to atoms that did not move. This effect contributes to a faster rate of relaxation in a gradient magnetic field.

NMR measurements of these and other parameters of the geologic formation can be done using, for example, the centralized MRIL® tool made by NUMAR Corporation, a Halliburton company, and the sidewall CMR tool made

25   by Schlumberger. The MRIL® tool is described, for example, in U.S. Pat. 4,710,713 to Taicher et al. and in various other publications including: "Spin Echo Magnetic Resonance Logging: Porosity and Free Fluid Index Determination," by Miller, Paltiel, Gillen, Granot and Bouton, SPE 20561, 65th Annual Technical Conference of the SPE, New Orleans, LA, Sept. 23-26, 1990;

30   "Improved Log Quality With a Dual-Frequency Pulsed NMR Tool," by Chandler,

Drack, Miller and Prammer, SPE 28365, 69th Annual Technical Conference of the SPE, New Orleans, LA, Sept. 25-28, 1994. Certain details of the structure and the use of the MRIL® tool, as well as the interpretation of various measurement parameters are also discussed in U.S. patents 4,717,876; 4,717,877; 4,717,878; 5,212,447; 5,280,243; 5,309,098; 5,412,320; 5,517,115, 5,557,200;

5   5,696,448 and 5,936,405, all of which are commonly owned by the assignee of the present invention. The Schlumberger CMR tool is described, for example, in U.S. Pats. 5,055,787 and 5,055,788 to Kleinberg et al. and further in "Novel NMR Apparatus for Investigating an External Sample," by Kleinberg, Sezginer and Griffin, J. Magn. Reson. 97, 466-485, 1992. The content of the above

10   patents and publications is hereby expressly incorporated by reference.

It has been observed that the mechanisms determining the measured values of T_1, T_2 and diffusion depend on the molecular dynamics of the formation fluids being tested and on the types of fluids present. Thus, in bulk volume liquids, which typically are found in large pores of the formation, molecular

15   dynamics is a function of both molecular size and inter-molecular interactions, which are different for each fluid. Water, gas and different types of oil each have different T_1, T_2 and diffusivity values. On the other hand, molecular dynamics in a heterogeneous media, such as a porous solid that contains liquid in its pores, differs significantly from the dynamics of the bulk liquid, and generally depends

20   on the mechanism of interaction between the liquid and the pores of the solid media. It will thus be appreciated that a correct interpretation of the measured signals can provide valuable information relating to the types of fluids involved, the structure of the formation and other well-logging parameters of interest.

If the only fluid in the formation is brine, a Carr-Purcell-Meiboom-Gill

25   (CPMG) pulse sequence with a short inter-echo spacing (T_e) and a long wait-time (T_w) can be applied for porosity determination and identification of capillary-bound and free water volumes. Total porosity logging methods are available to improve the quality of data used for determining pore volumes occupied by clay-bound and/or capillary-bound water. (See, for example, Prammer, M.G., *et al.*:

30   "Measurements of Clay-Bound Water and Total Porosity by Magnetic Resonance

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Logging," paper SPE 36522 presented at the 1996 SPE Annual Technical

Conference and Exhibition, Denver, Oct. 6–9). However, if hydrocarbons, such

as formation oil and/or gas or filtrate from oil-based mud, coexist with brine,

porosity determination and fluid typing (identification and quantification) with

NMR becomes more difficult.

5   Additional difficulties arise from the fact that NMR measurements impose

limitations on the logging speed. For example, it is known in the art that for

porosity determination all stimulated fluid protons should be sampled at full

polarization. Therefore, a long wait time T_w is required to completely detect the

magnetization from protons in slow T_1 processes. For gas and light oil under

10   typical formation conditions of temperature and pressure (100 - 300°F and 2,000 -

10,000 psi), T_1 values of a few seconds occur at low-frequency (1- to 2-MHz)

NMR. Wait times T_w of at least 10 seconds will capture nearly all the total proton

magnetization arising from the individual T_1 recovery rates encountered in

petroleum logging. Such long wait times, combined with acceptable depth

15   sampling, restrict the logging speed and reduce wellsite efficiency. One approach

addressing this problem is the application of prepolarization and multislice

(multifrequency) acquisitions implemented in the Magnetic Resonance Imaging

Logging™ MRIL-Prime tool. See Prammer, M.G., et al.: "Theory and Operation

of a New Multi-Volume NMR Logging System," paper DD presented at the 40th

20   Annual SPWLA Logging Symposium, Oslo, Norway, May 30 – June 3, 1999.

Still, it is believed that the capabilities of the MRIL tool have not yet been fully

utilized.

           Turning to the problem of fluid typing by NMR, it is known that it relies

on contrasts of characteristic parameters of the fluids, such as T_1, T_2, and

25   diffusivity. Two or more CPMG data sets, which may not be completely polar-

ized, are usually acquired to exploit parameter contrasts among the expected

fluids. Using NMR logging to determine reservoir porosity occupied by gas or

light oil currently requires data simultaneously acquired from at least two CPMG

sequences having different wait-times. Examples of this method are disclosed in

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U.S. Patent 5,936,405 to the assignee of the present application. The content of this patent is incorporated herein by reference for all purposes.

Dual-wait-time and dual-frequency methods have been applied to determine gas volumes in both clean and shaley sand formations. It is known that the success of the application depends primarily on two factors. First, adequate

5   signal-to-noise levels in an echo train difference has to be maintained so that the gas-filled porosity and its transverse relaxation time T_2 can be accurately characterized. Second, methods must be available to reliably estimate the longitudinal relaxation time T_1 of the hydrocarbon phase needed to apply a necessary amplitude correction to the apparent hydrocarbon-filled porosity. It is

10   clear that data acquisition and processing methods that address these two factors with success are highly desirable.

NMR technology has been successfully applied to distinguish fluids, and significant progress has been made in determining porosity in mixed-fluid situations. The reader is directed for details to the disclosure of U.S. provisional

15   patent application Ser. No. 60/106,259, filed October 30, 1998 to the assignee of the present application. The content of this application is incorporated herein by reference for all purposes. Still, quantitative analysis to determine actual hydrocarbon volumes present in the instrument's measurement space remains difficult because polarization corrections applied to apparent hydrocarbon

20   volumes rely on accurate knowledge of the hydrocarbon T_1.

Several researchers have acknowledged the importance of T_1 in quantitative fluid typing. Obtaining enough saturation-recovery data points to derive an accurate and precise T_1 distribution of a fluid at acceptable logging speeds and vertical resolution is difficult or nearly impossible. Consequently,

25   most quantitative analyses rely on T_1 values computed from correlation functions or by the application of assumptions to measured values. One disadvantage of such methods is that formation parameters, such as temperature, pressure, and fluid viscosity, may not be accurately known. In addition, attention must be directed to the ranges for which the correlation functions are valid. Prior art

30   methods of deriving T_1 involve either dual T_w's with one inter echo spacing T_e or

dual T_w's with multiple T_e's. See Akkurt, R., Prammer, M.G., and Moore, M.A.: "Selection of Optimal Acquisition Parameters for MRIL Logs," *The Log Analyst* (Nov.-Dec. 1996) 43; and Chen, S., *et al.*: "Estimation of Hydrocarbon Viscosity with Multiple TE Dual Wait-Time MRIL Logs," paper SPE 49009 presented at the 1998 SPE Annual Technical Conference and Exhibition, New Orleans, Sept.

5   27–30. Both methods referenced above assume that oil (or unpolarized brine) T_2 signals are totally separated from brine T_2 signals, which assumption is sometimes incorrect. Methods for obtaining gas T_1 values from NMR logs have not been previously developed.

In addition to being an important parameter for correcting apparent

10   volumes of fluids for under-polarization, T_1 computations play an important role in distinguishing one fluid from another. For example, it is well known that gas and light oil have large T_1 values, and thus can be separated from brine, which typically has lower values for T_1. Furthermore, fluid viscosity and self-diffusion coefficient D that can be obtained from a known T_1 value can be used to separate

15   gas from other fluids. Thus, large values for both T_1 and D reliably indicate the presence of gas or light oil in a formation. Fluid viscosity can also be used in grouping liquids. Various additional contrast mechanisms are known in the art and are described, for example, in the above-referenced U.S. provisional application 60/106,259, filed October 30, 1998 to the assignee of the present

20   application. Because T_1 relaxation times are not influenced by interactions between magnetic gradients and molecular diffusion, fluid viscosities obtained from measured T_1's are believed to be superior to other methods whenever a gradient-field logging tool is used or an internal magnetic gradient from the formation is present.

25   In view of the shortcomings of the prior art briefly outlined above, it is apparent that there is a need for a method and system that can take full advantage of the flexibility provided by current-generation NMR tools to enable the accurate calculation of T_1 and T_2 parameters for different fluids over the range of geologically meaningful values. This calculation in turn will enable reliable

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detection of the presence of gaseous and liquid hydrocarbons and estimation of their quantities.

Summary of the Invention

Accordingly, it is an object of the present invention to provide a method

5   and apparatus using nuclear magnetic resonance (NMR) techniques that obviate problems associated with the prior art.

In particular, a new triple-wait-time, multi-frequency acquisition method is disclosed and successfully tested. The method takes advantage of the multi-frequency operation of modern NMR logging tools to improve the signal-to-noise

10   ratio of the received signals at high logging speeds. Further, the acquisition method enables accurate estimation of volumes for hydrocarbon and/or free water in addition to traditional clay-bound and capillary-bound water volumes.

The new acquisition method uses optimized wait times to obtain better signal-to-noise ratios in echo train differential signals at faster logging speeds and

15   acceptable vertical resolution. In turn, these signals can be used to determine formation fluid volumes, as well as estimates of hydrocarbon T_1. Experiments performed on a mixture of dodecane ($C_{12}H_{26}$) and doped water, $C_{12}H_{26}$ and brine in a sandstone core, and fresh water produced fluid volumes with absolute errors of less than 1.5% for echo train differences with a signal-to-noise ratio larger than

20   4:1.

In another aspect, the present invention provides a data processing method that enables the accurate determination of both T_2 and T_1 parameters of hydrocarbons based on the use of at least two difference NMR signals obtained at different wait times. The data acquisition and processing method of the present

25   invention enable the determination of gas- and light-oil-filled porosity over a broad range of reservoir conditions. In another aspect, the present invention provides a decision mechanism to help in the selection of optimum acquisition parameters for logging applications.

In particular, in accordance with the present invention is provided a

30   (NMR) data acquisition method, comprising: providing a first set of CPMG

pulses associated with a first relatively short recovery time T_{WS1}; providing a second set of CPMG pulses associated with a second relatively short recovery time T_{WS2}, where T_{WS2} is longer than T_{WS1}; providing a third set of CPMG pulses associated with a relatively long recovery time T_{WL1}; receiving NMR echo signals from a population of particles in response to the first, second and third sets of

5   CPMG pulses; and processing the received NMR echo signals to provide a data representation associated with the longitudinal relaxation time constant T_1 of the population of particles.

In specific embodiments, the steps of providing the first, second and third sets of CPMG pulses are interleaved in time and/or are acquired in different

10   sensitive volumes. In these embodiments, the steps of providing the first, second and third sets of CPMG pulses are performed using a multi-frequency NMR logging tool. In different specific embodiments CPMG pulses associated with different recovery times may have either same or different operating frequencies. In a preferred embodiment, the first and second short recovery times T_{WS1} and

15   T_{WS2} are selected long enough to substantially polarize a water phase component in the population of particles, or in such manner that water-phase contribution is substantially canceled in a difference signal formed by subtracting NMR signals corresponding to a relatively short recovery time from NMR signals corresponding to the relatively long recovery time T_{WL1}.

20   In another aspect, in accordance with the present invention is provided a method for conducting NMR logging measurements, comprising: providing a data acquisition sequence comprising at least two sets of CPMG pulses having relatively short recovery times T_{WS1} and T_{WS2}, respectively, and at least one set of CPMG pulses having relatively long recovery time T_{WL1}; receiving NMR echo

25   signals from a population of particles in a geologic formation in response to the provided sets of CPMG pulses; processing the received NMR echo signals to determine a first and a second apparent volumes for at least one hydrocarbon fluid phase of the geologic formation, said first apparent volume being determined from a data representation associated with signals having short recovery time

30   T_{WS1}, and the second apparent volume being determined from a data

representation associated with signals having short recovery time T_{WS2}; providing a data representation associated with the longitudinal relaxation time constant T_1 of said at least one hydrocarbon fluid phase based on the determined first and second apparent volumes.

In a specific embodiment processing the received NMR echo signals

5   comprises: forming a first difference signal Edif1 by subtracting NMR signals having relatively short recovery time T_{WS1} from NMR echo signals having relatively long recovery time T_{WL}; computing T_2 distribution of the first difference signal Edif1; and determining a value for the T_2 relaxation time of said at least one hydrocarbon phase. In another embodiment, the method further comprises

10   forming a second difference signal Edif2 by subtracting NMR signals having relatively short recovery time T_{WS2} from NMR echo signals having relatively long recovery time T_{WL}. In a preferred embodiment, the method further comprises the step of computing the total porosity of the formation ϕ_t from the total apparent

porosity ϕ_{ta} and apparent volume corrections computed based on the provided

15   data representation associated with the longitudinal time constant(s) T_1 of the fluid phases.

In another aspect, the present invention is a method of operating a multi-volume NMR logging tool, comprising: (a) acquiring a first NMR echo train or sets of echo trains in a first sensitive volume of the tool, said first echo train(s)

20   carrying information about NMR signals with recovery time T_{WS1}; (b) acquiring a second NMR echo train or sets of echo trains in a second sensitive volume of the tool, said second echo train(s) carrying information about NMR signals having recovery time T_{WL}; (c) acquiring a third NMR echo train or sets of echo trains, said third echo train(s) carrying information about NMR signals with recovery

25   time T_{WS2}; (d) computing values for the transverse relaxation time T_2 and apparent volume for at least one hydrocarbon fluid phase based on the acquired NMR echo trains; and (e) providing a data representation associated with the longitudinal relaxation time constant T_1 of said at least one hydrocarbon fluid phase based on the determined first and second apparent volumes.

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In another aspect, the present invention is a NMR data processing method for use in borehole logging, comprising: selecting values for a second relatively short recovery time T_{WS2} using a known functional relationship based on estimates of: (a) a first relatively short recovery time T_{WS1} needed to polarize

5 water signals in a geologic formation surrounding the borehole; and (b) expected T_1 values for hydrocarbon fluid phases in the geologic formation surrounding the borehole; providing a data acquisition sequence comprising at least two sets of CPMG pulses having said relatively short recovery times T_{WS1} and T_{WS2}, respectively, and at least one set of CPMG pulses having relatively long recovery

10 time T_{WL}; processing NMR echo signals received in response to the data acquisition sequence to provide an estimate of the true values for the longitudinal relaxation time constant T_1 of hydrocarbon fluid phases in the geologic formation, wherein the accuracy of the estimates of the T_1 constant is controlled in the step of selecting.

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Brief Description of the Drawings

The present invention will be understood and appreciated more fully from the following detailed description taken in conjunction with the drawings in which:

FIG. 1 is an illustration of the triple-wait time activation sequence used in a preferred embodiment of the present invention;

FIG. 2 is a flow diagram illustrating the data processing method used in a preferred embodiment of the present invention;

FIG. 3 is an illustration of hypothetical saturation recovery curves for water, hydrocarbon phase and a mixture of water and the hydrocarbon phase used in a specific embodiment of the present invention;

FIG. 4 are waiting time T_{WS2} - T_{WS1} cross-plots that can be used in accordance with the present invention for the selection of optimum logging acquisition parameters;

FIG. 5 is an overlay of triple-wait-time echo trains obtained from CPMG experiments performed in experiments performed on a 1.26:1 mixture of doped water and $C_{12}H_{26}$ for different T_W;

FIG. 6 is a T_2 distribution, selected at random, from one of the 8-s T_W CPMG experiments performed on a doped-water/$C_{12}H_{26}$ mixture;

FIG. 7 shows overlays of difference echo trains for 30 CPMG triple-wait-time sequences performed on a doped-water/$C_{12}H_{26}$ mixture using the method of the present invention;

FIG. 8 is overlay of triple-wait-time echo trains obtained in accordance with the present invention in a laboratory setting from 28 CPMG experiments performed on a 22-p.u. sandstone core filled with a 4% KCl brine and $C_{12}H_{26}$;

FIG. 9 is a T_2 distribution from a 6-s T_w measurement performed on the brine- and $C_{12}H_{26}$-filled sandstone core in accordance with the present invention;

FIG. 10 shows overlays of difference echo trains for 28 CPMG triple-wait-time sequences performed on the brine- and $C_{12}H_{26}$-filled sandstone core sample, along with matched-filter curves;

FIG. 11 illustrates an improvement in signal-to-noise ratio of Edifl echo differences using the multifrequency triple-wait-time acquisition method of the present invention, compared with those obtained with a dual-T_w, dual frequency method.

FIG. 12 is a block diagram of the apparatus in accordance with a preferred

5   embodiment, which shows individual block components for controlling data collection, processing the collected data and displaying the measurement results.

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Description of Preferred Embodiments

A. Equipment

In accordance with the present invention, NMR measurements are made using tools capable of performing separate, quasi-simultaneous measurements in different sensitive volumes by switching the operating frequency of the tool.

5   Fig. 12 is a block diagram of a generic system used in accordance with the present invention, and shows individual block components for controlling data collection, for processing the collected data and displaying the measurement results. As shown in Fig. 12, the system has a portion 32 (generally comprising a magnet array and antenna(s)) which is arranged to be lowered into a borehole. The tool's

10   electronic section 30 comprises a probe controller and pulse echo detection electronics. The output signal from the detection electronics is processed by data processor 52 to analyze the relaxation characteristics of the material being investigated in the sensitive volume, generally designated as 34. The output of the data processor 52 is provided to the parameter estimator 54. Generally, data

15   processor 52 selects the desired data acquisition technique and the corresponding set of measurement parameters.

Dependent on the selected data acquisition technique, measurement cycle controller 55 provides an appropriate control signal to the probe. In a specific embodiment, data from the log measurement is stored in data storage 56. In a

20   preferred embodiment, raw data received by the tool can be pre-processed downhole by the electronic section 30. Data processor 52 is connected to display 58, which is capable of providing a graphical display of one or more measurement parameters, possibly superimposed on display data from data storage 56.

For the purposes of this invention it is important that the tool is capable of

25   "hopping" from one operating frequency to another, the effect of which is to shift the radial position of the resonant volume of the tool. The frequency shift is selected in such manner that two or more non-overlapping resonant volumes are formed; each new resonant volume associated with a different frequency being filled with fully relaxed protons. Hopping between two or more (i.e., K)

30   frequencies thus allows reducing the time between experiments approximately by

a factor of K, without compromising complete T_1 measurements or adopting imprecise empirical T_1/T_2 relationships; the logging speed for the tool can accordingly be increased approximately K times.

The components of the system of the present invention shown in Fig. 12 can be implemented in hardware or software, or any combination thereof suitable

5   for practical purposes. Preferably, the data processing algorithms used in accordance with the invention are programmed into software which is stored in a computer storage medium for execution on a computer, such as data processor 52. In a preferred embodiment, NMR measurements in accordance with the present invention are done using Numar Corporation's (a Halliburton Company) MRIL®

10 tools having multi-frequency capability, such as the MRIL® -Prime tool. Details of the structure, the operation and the use of logging tools, as illustrated in Fig. 12, are also discussed, for example, in U.S. patents 4,717,876; 4,717,877; 4,717,878; 5,212,447; 5,280,243; 5,309,098; 5,412,320; 5,517,115; 5,557,200; 5,696,448 and 5,936,405 to the assignee of the present application, the contents of

15 which are incorporated herein for all purposes.

B. Data acquisition

In accordance with a preferred embodiment of the present invention, the multi-frequency capability of the operating tool is used to provide a new data

20 acquisition method, which is particularly suitable for the detection of gas and other hydrocarbons on the basis of NMR measurements with different wait times T_W. To this end, with reference to Fig. 1, a novel interleaved pulse sequence is proposed using triple-wait-time activation.

Fig. 1 generally illustrates a method for measuring volumes occupied by

25 hydrocarbons, and in particular shows a triple-wait-time activation sequence of the preferred embodiment. As shown, the activation sequence used in a preferred embodiment of the present invention uses seven resonant frequencies, which are grouped into four frequency bands designated 1, 2, 3, and 4. The specific frequencies used in these four bands depend on the characteristics of the tool and

30 the desirable sensitive volume. In a specific embodiment using Numar

Corporation's MRIL tool, the nominal center frequencies for bands 1, 2, 3 and 4 shown in Fig. 1 are 620 kHz, 650 kHz, 680 KHz and 760 kHz, respectively. As shown, in a preferred embodiment of the method there are two frequencies each corresponding to frequency bands 1, 2, and 3. These two frequencies, denoted in Fig. 1 by plus and minus signs appended to the band number, are +6 and -6 kHz

5   relative to the band center frequency in a specific embodiment. In the embodiment illustrated in Fig. 1, band 4 is a single frequency band that operates at a nominal frequency of 760 kHz for the MRIL tool. It can be shown that in this embodiment the radial distance between the inner- and outer-most sensitive volumes is less than one inch.

10   For ease of notation, data groups acquired using identical wait times T_w have identical labels, and are designated A, B, C, D and E. As shown in Fig.1, in general there are four wait times involved in the measurements performed at the 1-, 1+, 2-, 2+, 3-, and 3+ frequencies - two relatively short wait times designated T_{WS1} and T_{WS2}, and two relatively long wait times, T_{WL1} and T_{WL2}. However, at

15   normal logging speeds measurement volumes with these frequencies are completely replenished with protons that have been fully polarized during the T_{WL1} and T_{WL2} delays. For example, this may be due to the length of the wait time interval and/or the use of pre-polarizing magnets. Thus, for practical purposes the activation sequence of the present invention effectively involves only one long

20   wait time T_{WL}, which is used for data processing purposes. In a preferred embodiment this wait time T_{WL} is selected as the longest delay time T_{WL1} shown in Fig. 1.

In accordance with the present invention, and with further reference to Fig. 2, four frequencies (1-, 1+, 2-, and 2+) in the activation sequence shown in

25   Fig. 1 provide improved signal-to-noise ratio in echo train differences compared with prior art data acquisitions made with dual-frequency tools. As explained below, measurements performed at these frequencies (data groups C and D) are generally used to obtain T_2 estimates and apparent hydrocarbon volumes. On the other hand, NMR signals obtained from the combination of the 1-, 1+, 2-, 2+, 3-,

30   and 3+ frequencies (data groups A, B, C and D) are used in accordance with the

present invention to determine hydrocarbon T_1 values. In turn, these values are used to make polarization corrections to apparent hydrocarbon volumes derived from the 1-, 1+, 2-, and 2+ frequency measurements.

In a preferred embodiment, measurements at frequency band 4 (data groups E in Fig. 1) consist of a small number of high-quality echoes. Data groups

5   E are used to improve the precision in measuring rapid T_2 decay components usually associated with clay-bound water and/or capillary-bound water.

In accordance with the present invention, the design of the activation sequence illustrated in a preferred embodiment in Fig. 1 also improves the logging speed of the tool. It is known in the art that under the influence of tool

10   motion, RF, magnetic field values, and sensitive volume can not be constant at a particular location in a formation. See, for example, Edwards, C.M.: "Effects of Tool Design and Logging Speed on T2 NMR Log Data," paper RR presented at the 38th Annual SPWLA Logging Symposium, Houston, June 15–18, 1997. As a consequence, apparent T_2 values decrease with increasing logging speed. It is

15   clear that the addition of more frequencies (measurement volumes) in accordance with the present invention causes a larger volume of formation to be sampled per unit length of tool motion, so that a greater signal-to-noise ratio (SNR) is attained. In the alternative, for a given SNR one can obtain higher logging speed. It has been determined that for the acquisition sequence illustrated in Fig. 1, using the

20   MRIL tool of the preferred embodiment, the maximum logging speed is about 900 ft/hr, which gives a vertical resolution of approximately 3 ft and minimizes the influence of logging speed on T_2 determination.

It will be appreciated by those of skill in the art that in alternative embodiments of this invention a different, for example larger, number of

25   frequency bands and/or frequencies per band can be used in the activation sequence. It should be apparent that in such alternative embodiments one can increase the SNR of the received signals by combining more data groups per data point. For example, with reference to Fig. 1, instead of two data groups C for the first data point (one at frequency band 1- and one at frequency band 2-) one can

30   use a higher number. In an alternative embodiment, a single data group can be

used per data point. As illustrated in Fig. 1, data for the three different recovery times need not necessarily be obtained from only three different frequencies. For example, two or more measurements associated with different frequencies can be combined (i.e., averaged) to result in a single data stream corresponding to either a short, or a long recovery time. Additional modifications in the parameters of

5   the pulse sequences can be applied, as known in the art. For example, it is known that the contrast between liquid and gas signals can be enhanced by using a slightly larger pulse-echo spacing for the CPMG train associated with the shorter recovery interval. Modifications of this type are straightforward extensions of the activation sequence illustrated in Fig. 1.

10   The activation sequence illustrated in a preferred embodiment in Fig. 1 is believed to have at least two significant advantages over the prior art, including dual-T_w, dual-frequency methods for determining volumes of gas or light oil. First, the addition of more frequencies (measurement volumes) causes a larger volume of formation to be sampled per unit length of tool motion so that a greater

15   signal-to-noise ratio (SNR) is attained in the echo train differential signals used to determine apparent hydrocarbon volumes. Second, the acquisition sequence has the important advantage that interlaced measurements having three wait times enable the computation of T_1 values for the hydrocarbon phases in the formation, as shown below.

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C. Data processing

In accordance with a preferred embodiment of the present invention, data acquired with the new activation sequence discussed above is processed as shown in Fig. 2. In particular, at step 10 raw echoes are received according to a triple-wait-time activation sequence, such as shown in Fig. 1. In step 20, in a preferred

5   embodiment the method applies certain corrections to the raw data generally designed to improve the signal-to-noise ratio of the received signal. In a specific embodiment, in step 20 the raw data undergoes a phase correction and/or a running average correction. Both corrections are known in the art and thus will not be considered in detail. For purposes of illustration, in a specific embodiment

10 implementing phase correction, if r(n) is the magnitude for the nth echo in a CPMG echo train, and a(n) is its angle (in radians) the phase correction for the CPMG echo train is given by the following pseudo-code:

1)   First find the Phase correction angle A over a group of M echos (where

15 M = 2-10 in a specific embodiment)

$$R*exp(j*A) = sum[r(n)*exp.(j*a(n))], n=1,...,M,$$

2)   Apply phase correction, i.e., phase rotation to the individual echos using

20

$$r(n)*exp.(j*a(n))*exp(-j*A)$$

3)   obtain phase corrected values using

$$Echoes = Re\{r(n)*exp.(j*a(n))*exp(-j*A)\}$$

25 where Re{.} is taking the real part.

It will be appreciated that the above processing sequence separates signal with noise in one channel and noise only in the secondary channel (i.e., the imaginary part following the correction), and has the additional benefit of reducing the original complex number representation to working with real

30 numbers.

In a specific embodiment, a running average correction (using 8 or 16 echos) can also be applied as known in the art in step 20 to further improve the signal-to-noise ratio.

With reference to Fig. 2, following step 20 the processing algorithm is separated into two branches. Generally, hydrocarbon volumes and T_1 estimates

5   are determined in the right branch. In the left branch, the long T_W and frequency 4 echo data are inverted to obtain T_2 distributions that are combined to obtain an apparent total porosity, capillary- and clay-bound water volumes, and other parameters of interest.

Focusing first on the determination of hydrocarbon volumes, in

10   accordance with the present invention the method generally comprises four steps. First, the T_2's of the hydrocarbons are determined. In the second step, the determined T_2's are used to extract hydrocarbon signal amplitudes from two echo difference trains. In accordance with the present invention these amplitudes are used to compute T_1 values for the hydrocarbons, as shown below. Corrections for

15   hydrogen index and polarization (T_1) are applied to the signal amplitudes in the last step to compute the hydrocarbon volumes. In the left processing branch, apparent total pore (or fluid) volume ϕ_{ta} is derived from the T_{WL} and frequency 4 T_2 distributions. Corrected total pore volume ϕ_t is then computed as the sum of ϕ_{ta} and hydrocarbon volume corrections ($\Delta\phi_o$ and $\Delta\phi_g$) that are functions of the

20   T_1's and hydrogen indices of the hydrocarbon phases. An additional correction ($\Delta\phi_w$) may be required for under-polarized water, before various other parameters of interest are determined.

In particular, at step 30 of the method is formed the difference Edifl between echo signals with a long wait time T_{WL} and the first short wait time T_{WS1}.

25   As shown in Fig. 1, in a preferred embodiment two or more measurements (data groups) associated with different frequencies can be combined (i.e., averaged) to result in a single data stream. Again with reference to Fig. 1, forming the difference Edifl corresponds to forming differences between echo signals in the C and D data groups. It will be appreciated by those skilled in the art that the

30   difference signal carries information essentially about the hydrocarbon phase

which has a single T_1 and T_2 values, because the water contribution is canceled out. In the following step 40 is computed the T_2 spectrum of the Edif1 difference signal. Various ways of computing this spectrum are known in the art. In a preferred embodiment, one can use the MAP algorithm as disclosed in U.S. Pat. No. 5,517,115 to the assignee of the present application, or in Prammer, M.G.:

5   "NMR Pore Size Distributions and Permeability at the Well Site," paper SPE 28368 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 25–28. The contents of these publications are incorporated herein by reference.

In step 50 of the method are determined T_2 values for the corresponding

10   hydrocarbon components from the T_2 spectrum of the difference signal. In a specific embodiment, this involves locating the peaks of the T_2 spectrum and assigning the values for the peak(s) as the T_2 values of the respective hydrogen components. It will be appreciated that relatively long T_2 peak values generally correspond to oil components, while relatively short T_2 values generally

15   correspond to gas components.

Having determined the value(s) for the T_2 of the hydrocarbon components, in the following steps 60-90 the difference signals Edif1 and Edif2 are used to compute two apparent hydrocarbon volumes. In a preferred embodiment, this is done by using matched filters to fit exponential terms to each echo difference

20   train. First, in step 80 is formed the Edif2 difference signal between the T_{WL} and T_{WS2} signals. With reference to Fig.1 this corresponds to forming the difference between the A and B data groups. It will be appreciated that T_{WS2} is longer than T_{WS1}.

Next, the apparent hydrocarbon signal amplitudes (gas and/or oil), A_0, in

25   the Edif1 and Edif2 echo difference trains are obtained by fitting the equation with matching filter, in this case $\exp(-t/T_{2mp})$, for gas and oil:

$$A(t) = A_o e^{-\frac{t}{T_{2mp}}},\qquad\qquad (1)$$

30

where $A(t)$ represents the average echo difference amplitude at echo time t and T_{2mp} is the most probable amplitude T_2 value, determined from step 50 for a hydrocarbon zoom, for the hydrocarbon phase component (gas or oil). On output, method steps 70 and 90 will give the two apparent hydrocarbon signal amplitudes A_0, corresponding to the two difference signals (Edif1 and Edif2).

5   Next, in step 100 of the method is determined the value for the T_1 parameter(s) for the hydrocarbon phases, using the following equation (separately for oil (phase p1) and gas (phase p2)):

10
$$\frac{e^{-\frac{T_{WSI}}{T_{1,p1,2}}} - e^{-\frac{T_{WL}}{T_{1,p1,2}}}}{e^{-\frac{T_{WS2}}{T_{1,p1,2}}} - e^{-\frac{T_{WL}}{T_{1,p1,2}}}} = \frac{A(T_{WSI}, T_{WL}, T_{1,p1,2})}{A(T_{WS2}, T_{WL}, T_{1,p1,2})} \tag{2}$$

where $A(T_{WS1}, T_{WL}, T_{1,p1,2})$ represents the apparent hydrocarbon amplitude from

15   Edif1, and $A(T_{WS2}, T_{WL}, T_{1,p1,2})$ is the apparent hydrocarbon amplitude from Edif2. In the case when there is only one hydrocarbon phase, Eqn. (2) above reduces to:

20
$$\frac{e^{-\frac{T_{WSI}}{T_{1,p1}}} - e^{-\frac{T_{WL}}{T_{1,p1}}}}{e^{-\frac{T_{WS2}}{T_{1,p1}}} - e^{-\frac{T_{WL}}{T_{1,p1}}}} = \frac{A(T_{WSI}, T_{WL}, T_{1,p1})}{A(T_{WS2}, T_{WL}, T_{1,p1})} \tag{3}$$

The T_1's from the triple-wait-time experiments are found by solving Eqn.

25   (2) or Eqn. (3) when $A(T_{WS1}, T_{WL}, T_{1,p1})$ and $A(T_{WS2}, T_{WL}, T_{1,p1})$ are replaced with the Edif1 and Edif2 signal amplitudes, respectively, for each experiment. The most probable value for T_{1mp} in a hydrocarbon zoom of formation, is then used in step 110 to compute corrected hydrocarbon volumes ϕ_h. In a preferred embodiment, this is done by applying

30

$$\phi_h = \frac{A_{o,Edifl}}{HI_h \left(e^{-\frac{T_{iw,1}}{T_{imp}}} - e^{-\frac{T_{iw}}{T_{imp}}} \right)}, \tag{4}$$

where HI_h is the hydrogen index of the hydrocarbon phase. In a specific
embodiment, the most probable value T_{imp} is found as average over a number M
of experiments, where for example, M = 30 which corresponds to data points
acquired in a hydrocarbon zoom of formation. It will be appreciated that in
alternative embodiments the hydrogen index correction can be obtained using
different methods from the known parameters.

Turning next to the left branch of the processing algorithm illustrated in
Fig. 2, in step 120 is determined the total apparent porosity ϕ_{ta}, using T_{WL} and
frequency 4 T_2 distributions. In a specific embodiment, the determination is done
by combining a long T_W (i.e., data group A and/or C) and frequency 4 echo data
(data group E). In a specific embodiment, the combination is done by separately
computing the T_2 spectra of the two echo signals and generating a composite
signal where below certain limit, i.e., 4 ms, data group E is used, while above that
merge point the T_{WL} distribution is applied. In alternative preferred embodiment,
the combination is done entirely in the time domain, as described in U.S.
Provisional Application 60/098,596, filed August 31, 1998 to the assignee of the
present application. The content of this application is incorporated herein by
reference.

In the following step 130 the total porosity ϕ_t is computed from the total
apparent porosity ϕ_{ta}, and corrections for HI and polarization of water and
hydrocarbons based on the apparent fluid volumes and T_1s computed in the right
processing branch. In a specific embodiment, corrected total porosity is obtained
using the corrections in Eqn. (4). Thus, for example, oil and gas corrections can
be computed in a specific embodiment by $\phi_h * \exp(-T_{WL} / T_{1mp})$. In certain
instances correction for under-polarized water can be computed as a fluid phase
in the right branch of the algorithm. Alternative corrections for water can be
applied as known in the art.

In the following step 140 is determined the total water volume as the difference between the total porosity and the total hydrocarbon volume. From the quantities determined thus far, in the final step 150 of the algorithm are computed various parameters of interest, as shown in a specific embodiment in Fig. 2.

The data processing method illustrated in Fig. 2 is a preferred embodiment
5   designed to operate with the data acquisition sequence in Fig. 1. Alternative embodiments are possible and will be apparent to persons of skill in the art. For example, the individual steps discussed above can be implemented using alternative signal models and/or approaches. Thus, the specific use of equations (1) - (4) is not required in accordance with the present invention. For example,
10   once the water contribution is canceled out, in the right branch of the algorithm one may consider different signal models, with increased number of parameters for increased accuracy.

D. Examples
15

The application of the new method for determining the hydrocarbon T_1 values is next illustrated in the following two cases.

Case 1: A two-phase mixture, consisting of water and light oil (possibly oil filtrate) or water and gas.
20
Following echo train correction, two echo train differences, Edif1 and Edif2, are used to eliminate the broadly distributed water signal, Edif1 = T_{WL} - T_{WS1} (data group C minus group D) data and Edif2 = T_{WL} - T_{WS2} (A group minus B group) data. Next, Edif1 and Edif2 are used to compute two apparent hydrocarbon volumes by using matched filters to fit exponential terms to each echo
25   difference train. The T_1 for the hydrocarbon phase T_{1p3l} is given by

$$\frac{e^{-\frac{T_{WS1}}{T_{1,p1}}} - e^{-\frac{T_{WL}}{T_{1,p1}}}}{e^{-\frac{T_{WS2}}{T_{1,p1}}} - e^{-\frac{T_{WL}}{T_{1,p1}}}} = \frac{A(T_{WS1}, T_{WL}, T_{1,p1})}{A(T_{WS2}, T_{WL}, T_{1,p1})},$$

30

where $A(T_{WS1}, T_{WL}, T_{1,p1})$ represents the apparent hydrocarbon amplitude from Edif1, and $A(T_{WS2}, T_{WL}, T_{1,p1})$ is the apparent hydrocarbon amplitude from Edif2, see Eqn. (3) above. For known values of T_{WL}, T_{WS1}, T_{WS2} and the apparent hydrocarbon amplitudes from Edif1 and Edif2, the parameter T_1 of the hydrocarbon phase can be determined readily.

5

    Case 1: A three-phase mixture of water, light oil (or oil filtrate), and gas.

    Matched-filter exponential fitting is performed on the Edif1 and Edif2 echo differences as above to obtain apparent volumes for each of the hydrocarbon phases. T_1's for the hydrocarbon phases are given by applying Eqn. (2) separately
10 for oil (phase p1) and gas (phase p2). As before, T_1 values for the hydrocarbons can be computed directly from the known quantities.

    Based on the above discussion, it is apparent that a key element of the
15 method for determining hydrocarbon T_1 values is the selection of the wait times. Generally, all T_W values should be long enough to polarize the water signal fully, so that echo difference signals (i.e., Edif1, Edif2, ...) contain only hydrocarbon signals that have discrete T_1 and T_2 values for each phase. In addition, in accordance with the present invention the left side of Eqns. (2) and (3) must be
20 from 1.4 to 5 for T_1 to be accurately determined. Moreover, the delay times must be chosen to keep the overall activation set cycle time as short as possible to maximize logging speed.

    In a typical Gulf of Mexico gas well, water T_2 signals range from a few hundred microseconds to a few hundred milliseconds, and gas T_1's are on the
25 order of a few seconds. See, e.g., Akkurt, R., _et al._: "NMR Logging of Natural Gas Reservoirs." Paper N presented at the 36th Annual SPWLA Logging Symposium, Paris, June 26–29, 1995. Fig. 3 shows hypothetical saturation recovery curves for water (assuming $T_1 = 0.25$ s) and hydrocarbon (assuming $T_1 = 3$ s). The uppermost curve is for water with an assumed $T_1 = 0.25$ s. From
30 this, it can be seen that a T_W of 1 second will achieve more than 95% polarization

of the water signal. The bottom curve depicts a hydrocarbon phase (T_1 = 3 s). The middle curve represents an equal mixture of the water and hydrocarbon phases. For two-phase mixtures of these fluids, accurate values for hydrocarbon T_1 and volume can be obtained with the triple-wait-time method when wait times of 1, 3, and 8 seconds (indicated by the vertical lines) are used.

5   Shown in Fig. 4 are crossplots of T_{WS1} and T_{WS2} with contour lines of

$$ F = \left[e^{-(T_{WS1}/T_1)} - e^{-(T_{WL}/T_1)} \right] \Big/ \left[e^{-(T_{WS2}/T_1)} - e^{-(T_{WL}/T_1)} \right] \tag{5} $$

10   for T_1 values from 3 to 6 seconds. The T_{WS2}-T_{WS1} crossplots illustrate the selection of triple-wait-time combinations according to the method of the present invention dependent on expected hydrocarbon T_1 values (rows of panels) and long wait times, (columns of panels). Contour lines according to Eqn. (5) start at F = 1 and increase by increments of 0.1 toward the upper left corner in each
15   panel. For good hydrocarbon T_1 determinations, F should be 1.4 or larger. With reference to Fig. 4, if a 1-second T_w (T_{WS1}) is needed to fully polarize the water signal and the possible hydrocarbon T_1 could be as large as 6 seconds, then for an 8-second T_{WL} the charts suggest that T_{WS2} should be 3 seconds.

In accordance with the present invention, these crossplots can be used in
20   selecting the best wait-time combination for a given set of logging conditions. For example, based on the above criteria and the information in Figs. 3 and 4, the three T_W values for a typical Gulf of Mexico well can be selected as 1, 3, and 8 seconds. It should be apparent that for different conditions different T_W can be selected using the crossplots shown in Fig. 4, or the mathematical relationship
25   expressed in Eqn. (5). The derivation of these tools is believed to be a significant contribution of the present invention.

30

E. Applications

One of the main applications of the system and method of this invention stems from the need to determine accurately the T_1 parameter corresponding to slow T_2 decay components in echo difference signals usually associated with light hydrocarbons, such as light oil, oil filtrate, and gas or free brine in large pores.

5 Three experiments were performed with mixtures of $C_{12}H_{26}$ and doped water, a sandstone core filled with water and $C_{12}H_{26}$, and a freshwater-filled tank to demonstrate the effectiveness of the proposed method. A MARAN-1 laboratory spectrometer operating at a 1-MHz resonant frequency was used to obtain measurements on the bulk $C_{12}H_{26}$/doped water and sandstone core samples. A

10 MRIL-Prime logging tool was used to perform experiments in a water-filled tank. The following describes the procedures and results obtained from each experiment.

Mixture of doped water and dodecane.

15

A 3.5-in. (inside diameter) glass sample holder was used to measure bulk fluids in the MARAN spectrometer. To determine the true volumes of the samples in arbitrary units, CPMG pulse sequences were used to make 10 measurements on separate samples of doped water and $C_{12}H_{26}$. The mean volume

20 of the doped water sample was determined to be 136±0.7 arbitrary units. Similarly, the mean volume for the $C_{12}H_{26}$ sample was found to be 108±0.9 arbitrary units. Inversion recovery measurements, consisting of 51 inversion recovery times, were performed separately on the samples. The data from these experiments were used to find bulk-fluid T_1 values of 395±1.8 and 995±4.7 ms,

25 respectively, for the doped water and $C_{12}H_{26}$ samples.

The samples of doped water and $C_{12}H_{26}$ were combined and mixed to form a 1.26:1-volume ratio of doped water to $C_{12}H_{26}$. A series of tests were performed on the mixture in which different wait-time combinations were used to collect sets of 30 CPMG triple-wait-time experiments consisting of 5,000 1-ms echoes.

30 Data from these tests were used to derive the $C_{12}H_{26}$ volumes and T_1's that are

shown in **Table 1** below for each triple-wait-time combination trial. By comparing the true values with the results in Table 1, the smallest error occurred when a triple-wait-time combination of 1, 2, and 8 seconds was used.

Table 1—Optimization of T_ws for determining T_1 and volume of hydrocarbon in a mixture of dodecane and doped water					
	True values	TWs=1, 1.5,& 8 s	TWs=1, 2, & 8 s	TWs=1, 2.5,& 8 s	TWs=1, 3, & 8 s
T_1 of $C_{12}H_{26}$ (ms)	995[a]	1162	991	1047	893
Standard dev. of T_1 (ms)	4.7	158.1	66.4	74.2	150.9
Volume of $C_{12}H_{26}$ (arb.)	108[b]	92.9[c]	106.7[c]	102[c]	119.5[c]
Standard dev. of the volume (arb.)	0.9	3.3	4.0	4.1	7.1

[a]True T_1 was derived from an inversion recovery measurement with 51 inversion recovery times performed on a bulk sample.

[b]Reported sample volume is the average signal amplitude at t = 0 obtained from T_2 inversions performed on 10 CPMG measurements.

[c]The volume of $C_{12}H_{26}$ in the doped water/$C_{12}H_{26}$ mixture is the same as the $C_{12}H_{26}$ sample.

Fig. 5 shows the triple-wait-time echo trains acquired for the 1-, 2-, and 8-second combination. The MAP algorithm was used to perform 21-bin T_2 inversions of the, 8-second wait-time echo trains. Overlay of triple-wait-time echo trains obtained in the laboratory from 30 CPMG experiments performed on a 1.26:1 mixture of doped water and $C_{12}H_{26}$. The top set of curves is the 8-second T_w. The middle set is the 2-second T_w. The bottom set of curves was acquired with a 1-second T_w. For details of the MAP algorithm the reader is directed to U.S. Pat. No. 5,517,115; and Prammer, M.G.: "NMR Pore Size Distributions and Permeability at the Well Site," paper SPE 28368 presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, Sept. 25–28, the disclosure of which is hereby incorporated by reference.

An example from one experiment, Fig. 6 shows a uni-modal distribution of T_2 values. This T_2 distribution was selected at random from one of the 8-s T_w CPMG experiments performed on the doped-water/$C_{12}H_{26}$ mixture using this invention. A MAP inversion with 21 T_2 bins (indicated by the stair-step curve) was performed. The bin amplitudes, shown as the line joining T_2 times at the bin

5   centers, have been normalized to the maximum bin amplitude. The dotted curve indicates the normalized cumulative amplitude as a function of T_2 time. The two liquid phases are not resolved in the T_2 spectrum at the signal-to-noise conditions for the single experiment shown. A similar situation occurs in many logging applications, which can make fluid typing difficult with only one kind of NMR

10   acquisition.

To obtain only $C_{12}H_{26}$ signals, the triple-wait-time echo trains were used to generate two sets of echo train differences for each experiment, shown in Fig. 7. Fig. 7 shows overlays of difference echo trains for the 30 CPMG triple-wait-time sequences performed on a doped-water/$C_{12}H_{26}$ mixture. The top panel

15   shows the Edif2 (8-second minus 2-second) differences and the bottom panel shows the Edif1 (8-second - 1-second). In addition, each panel includes the corresponding matched-filter fitted curves that provided the apparent $C_{12}H_{26}$ volume for each experiment.

Assuming the doped water signals are eliminated in the Edif1 (8-second

20   minus 1-second echo difference) echo train, Edif1 was used to determine the most probable hydrocarbon T_2 value - T_{2mp}. The value was found by performing T_2 inversions on each Edif1 echo train and computing the average of the largest T_2 modes observed in the 30 distributions.

Apparent $C_{12}H_{26}$ signal amplitudes, A_0, in the echo difference trains were

25   obtained for each experiment by fitting the Eqn. (1), reproduced here for convenience

$$A(t) = A_o e^{-\frac{t}{T_{2mp}}},$$

where A(t) represents the average echo difference amplitude at echo time t to

30   both Edif1 and Edif2.

The apparent T_1's from the triple-wait-time experiments were found by solving Eq. 1 when $A(T_{WS1}, T_{WL}, T_{1,pl})$ and $A(T_{WS2}, T_{WL}, T_{1,pl})$ were replaced with the Edif1 and Edif2 $C_{12}H_{26}$ signal amplitudes, respectively, for each experiment. The most probable T_1 (average of the 30 experiments), T_{1mp}, was then used to compute corrected hydrocarbon volumes ($C_{12}H_{26}$) ϕ_h by applying Eqn. (4)

5

$$\phi_h = \frac{A_{o,Edif1}}{HI_h \left(e^{-\frac{TWS1}{T_{1mp}}} - e^{-\frac{TWL}{T_{1mp}}} \right)} ,$$

where HI_h is the hydrogen index of the hydrocarbon, which is equal to 1 for

10      $C_{12}H_{26}$. The average T_1 and its standard deviation along with the average corrected volume and its standard deviation are given in Table 1 above. For the 1, 2, and 8-second wait-time combination, the absolute error for T_1 is 0.4%, and the absolute error for the volume of $C_{12}H_{26}$ is 1.2%.

15
Sandstone core filled with water and dodecane.

A three-step process was used to prepare 3.5- (diameter) by 4.5-in. sandstone core having 22.06% porosity for laboratory NMR experiments with water and $C_{12}H_{26}$ pore fluids. The core was cleaned and saturated with a 4%

20   potassium chloride (KCl) brine solution under 1 atmosphere of pressure. Then the sample was desaturated to a capillary pressure of 50 psi, and the brine volume in the core was decreased from 151.9 to 32.4 cm^3. Under atmospheric conditions, 119.5 cm^3 of $C_{12}H_{26}$ were added to the sample, and the core was placed in a closed glass sample holder before making NMR measurements.

25   As before, several triple-wait-time combinations were investigated to determine the best set of wait times for the saturation state. Sets of 28 triple-wait-time CPMG pulse sequences were collected, which consisted of 9,000 0.4-ms echoes, for each wait-time combination. Data from these tests were used to derive the $C_{12}H_{26}$ volumes and T_1's that are shown in **Table 2** for each wait-time

30   combination tried. The true $C_{12}H_{26}$ T_1 value for these experiments was taken to

be the same as the value determined in the bulk fluid experiments, and true $C_{12}H_{26}$ volume was normalized to core porosity. By comparing the true values with the results in Table 2, the smallest error occurred when a triple-wait-time combination of 0.4, 1, and 6 seconds was used.

5

Table 2—Optimization of T_ws for determining T_1 and volume of hydrocarbon in a sandstone core filled with water and dodecane					
	True values	TWs=0.4, 0.8,& 6 s	TWs=0.4, 1 & 6 s	TWs=0.4, 1.2,& 6 s	TWs=0.4, 1.4,&6s
T_1 of $C_{12}H_{26}$ (ms)	995*	1149	1050	1157	1162
Standard dev. of T_1 (ms)	4.7	12.5	12.0	11.6	10.5
Volume of $C_{12}H_{28}$ (arb.)	17.35^d	17.09	17.10	16.97	17.02
Standard dev. of the volume (arb.)	0.140	0.060	0.060	0.061	0.073

10

15

*True T_1 was derived from an inversion recovery measurement with 51 inversion recovery times performed on a bulk sample.

^{d}Actual $C_{12}H_{26}$ volume = $C_{12}H_{26}$ saturation x core porosity.

20

The triple-wait-time echo trains acquired with the 0.4-, 1-, and 6-second combination are displayed in Fig. 8. The figure shows overlay of triple-wait-time echo trains obtained in the laboratory from 28 CPMG experiments performed on a 22-p.u. sandstone core filled with a 4% KCl brine and $C_{12}H_{26}$. The top set of curves is the 6-second T_w. The middle set is the 1-second T_w. The bottom set of curves was acquired with a 0.4-second T_w.

Fig. 9 shows the results of a 21-bin inversion performed on one of the 6-second T_w echo trains. The figure illustrates a T_2 distribution, selected at random, from one of the 6-s T_w measurements performed on the brine- and $C_{12}H_{26}$-filled sandstone core. The sharp, high-amplitude peak in the 1,000-ms bin

comes from the $C_{12}H_{26}$. The two lower amplitude peaks to the left are from the residual brine. The cumulative amplitude ratio (dotted curve) indicates that the volume ratio of $C_{12}H_{26}$ to water is approximately 4:1, close to the materials balance ratio of 3.7:1.

Edif1 and Edif2 echo differences (shown in Fig.10) were generated from the triple-wait-time echo trains to cancel the residual water signal. The most probable hydrocarbon T_2 was extracted by inverting the Edif1 (6-second minus 0.4-second echo difference) echo trains. More specifically, Fig. 10 shows overlays of difference echo trains for the 28 CPMG triple-wait-time sequences performed on the brine- and $C_{12}H_{26}$-filled sandstone core sample. The top panel shows the Edif2 (6-second minus 1-second) differences. The bottom panel shows the Edif1 (6-second minus 0.4-second). Matched-filter fitted curves are also shown for each experiment that provided the apparent $C_{12}H_{26}$ volume.

Edif1 and Edif2 were each fit to the exponential relationship in Eq. (1) to obtain the apparent $C_{12}H_{26}$ signal amplitudes that were used in Eq. (3) to compute an apparent T_1 for each CPMG triple-wait-time sequence. Eq. (4) was then used to compute corrected $C_{12}H_{26}$ volumes for comparison with the true value. The absolute error for T_1 is 5.5%, and the absolute error for the volume of $C_{12}H_{26}$ is 1.4%. The Edif1 signal-to-noise ratio is defined for the examples in this paper as the first echo difference amplitude divided by the standard deviation of the mean of the last 100 echo difference amplitudes. Edif1 signal-to-noise ratio was approximately 5:1 in this series of experiments, compared with the 7:1 ratio obtained during the bulk fluid mixture experiments discussed previously. The larger errors obtained in this case are attributed to the poorer signal-to-noise quality of the measurements.

Freshwater tank.

The triple-wait-time method was also tested by the use of an MRIL-Prime tool in a freshwater-filled tank in which the water has a volume of 100 porosity units (p.u.) and a T_1 of approximately 2.5 seconds.

Again, several wait-time combinations were tried. The activation set shown in Fig. 1 was used to acquire 48 sets of CPMG pulse sequences in the water tank for each wait time combination. In all but frequency 4, the collected echo trains consisted of 400 1.2-ms echoes. **Table 3** lists the T_1 and volume results from each test, which show that the optimum combination of wait times for this setup is 1, 3, and 10 seconds.

Table 3—Optimization of T_ws for determining T_1 and volume of free fresh water in a water tank					
	True values	**TWs=1, 3,& 10 s**	**TWs=2, 3 & 10 s**	**TWs=1, 3.5,& 12 s**	**TWs=1.5, 3.5,&6s**
T_1 of fresh water (ms)	~2500[c]	2180	2010	2059	2018
Standard dev. of T_1 (ms)		176.2	394.2	170.0	216.2
Volume of $C_{12}H_{26}$ (arb.)	100	100.4	99.6	102	102
Standard dev. of the volume (arb.)		2.43	4.35	2.81	3.13

[c]The true T_1 and the volume of the water were obtained in a water tank used to calibrate MRIL-Prime tools.

Though an accurate water volume was obtained from the series of experiments, the water T_1 value obtained with the triple-wait-time method had a relatively large absolute error of 15%. It is believed that the acquisition time of 0.48 seconds (400 echoes x 1.2 ms/echo), which is short compared with the T_2 of bulk water and the 4:1 Edifl signal-to-noise ratio, contributed substantially to this error.

The activation set outlined in Fig. 1, however, has an important advantage over dual-frequency, dual-T_w activations. (See Akkurt, R., *et al.*: "NMR Logging of Natural Gas Reservoirs," Paper N presented at the 36th Annual SPWLA Logging Symposium. Paris, June 26–29, 1995). Because four frequencies are

available to collect Edifl echo-difference data, the signal-to-noise quality is 1.4 times better compared with the same data acquired with a dual-frequency activation.

Specifically, Fig. 11 shows how the multifrequency triple-wait-time acquisition method, developed for the MRIL-Prime tool, improves the signal-to-
5   noise ratio of Edifl echo differences compared with those obtained with a dual-T_w, dual frequency method. The examples shown were obtained in a freshwater-filled calibration tank. The MRIL-Prime Edifl difference echo trains are displayed in the top panel. The dual-T_w dual frequency Edifl appears in the bottom panel. The multifrequency triple-wait-time method gives an echo
10   difference signal-to-noise ratio that is 1.4 times better. The increase in Edifl signal-to-noise ratio, shown in Fig. 11, is important because it influences the accuracy of T_2's, T_1's, and volumes of hydrocarbons (or free brine) derived from multi-wait-time measurements.

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Based on the above, the inventors have found that the proposed data acquisition and processing method result in substantial improvements over prior art methods. Thus, for NMR signal differences having signal-to-noise ratios larger than 4:1, the absolute errors in determining fluid volume were less than
20   1.5%. In general, the new acquisition method brings a 1.4-time improvement to echo difference signal-to-noise ratios compared with previous implementations of dual-T_w logging with dual-frequency tools. The triple-wait-time technique has been applied successfully to two-phase or three-phase mixtures of water and hydrocarbons - light oil (or oil filtrate) and gas.

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Mathematical Foundations

The following provides the mathematical foundation for the method outlined above. The time-dependent NMR T_2 signal for a three-phase mixture of oil, gas, and water in a water-wet formation can be expressed as a weighted sum of exponential terms

5

$$
A(t, T_W) = HI_g \left(1 - e^{-\frac{T_W}{T_{1g}}} \right) \sum_i P_g(T_2(i)) e^{-\frac{t}{T_{2(i)}}}
$$

$$
+ HI_o \left(1 - e^{-\frac{T_W}{T_{1o}}} \right) \sum_i P_o(T_2(i)) e^{-\frac{t}{T_{2(i)}}} \qquad \text{(A-1)}
$$

10

$$
+ \sum_i P_w(T_2(i)) \left(1 - e^{-\frac{T_W}{T_{1w}(i)}} \right) e^{-\frac{t}{T_{2(i)}}}
$$

where $P_g(T_2)$, $P_o(T_2)$, $P_w(T_2)$ are the T_2 incremental porosity spectra of gas, oil and

15   water, respectively. For water, T_1 and T_2 are assumed to be linked through a constant ratio. See, e.g., Kleinberg, R.L., et al.: "Nuclear Magnetic Resonance of Rocks: T_1 vs T_2," paper SPE 26470 presented at the 1993 SPE Annual Technical Conference and Exhibition, Houston, Oct. 3-6. Therefore, the index of T_{1w} is correlated with T_2. If the hydrocarbon signals are limited to singular T_2 times,

20   then Equation A-1 simplifies to

$$
A(t, T_W) = HI_g \left(1 - e^{-\frac{T_W}{T_{1g}}} \right) \phi_g e^{-\frac{t}{T_{2g}}}
$$

25

$$
+ HI_o \left(1 - e^{-\frac{T_W}{T_{1o}}} \right) \phi_o e^{-\frac{t}{T_{2o}}} \qquad \text{(A-2)}
$$

$$
+ \sum_i P_w(T_2(i)) \left(1 - e^{-\frac{T_W}{T_{1w}(i)}} \right) e^{-\frac{t}{T_{2(i)}}}
$$

30

For triple-wait-time method, three similar equations can be used to represent time-dependent signal amplitudes in which the actual wait times are substituted for T_w

$$A(t, T_{WL}) = HI_g \left(1 - e^{-\frac{T_{WL}}{T_{1g}}} \right) \phi_g e^{-\frac{t}{T_{2g}}}$$

$$+ HI_o \left(1 - e^{-\frac{T_{WL}}{T_{1o}}} \right) \phi_o e^{-\frac{t}{T_{2o}}} \qquad\qquad (A\text{-}3)$$

$$+ \sum_i P_w(T_2(i)) \left(1 - e^{-\frac{T_{WL}}{T_{1w}(i)}} \right) e^{-\frac{t}{T_{2(i)}}}$$

$$A(t, T_{WS1}) = HI_g \left(1 - e^{-\frac{T_{WS1}}{T_{1g}}} \right) \phi_g e^{-\frac{t}{T_{2g}}}$$

$$+ HI_o \left(1 - e^{-\frac{T_{WS1}}{T_{1o}}} \right) \phi_o e^{-\frac{t}{T_{2o}}} \qquad\qquad (A\text{-}4)$$

$$+ \sum_i P_w(T_2(i)) \left(1 - e^{-\frac{T_{WS1}}{T_{1w}(i)}} \right) e^{-\frac{t}{T_{2(i)}}}$$

$$A(t, T_{WS2}) = HI_g \left(1 - e^{-\frac{T_{WS2}}{T_{1g}}} \right) \phi_g e^{-\frac{t}{T_{2g}}}$$

$$+ HI_o \left(1 - e^{-\frac{T_{WS2}}{T_{1o}}} \right) \phi_o e^{-\frac{t}{T_{2o}}} \qquad\qquad (A\text{-}5)$$

$$+ \sum_i P_w(T_2(i)) \left(1 - e^{-\frac{T_{WS2}}{T_{1w}(i)}} \right) e^{-\frac{t}{T_{2(i)}}}$$

Models of the time-dependent signals in the Edif1 and Edif2 echo
difference trains are obtained when Eqs. A-4 and A-5 are subtracted from Eq.
A-3,

$$Edif1(t) = HI_g \phi_g \left(e^{-\frac{T_{WS1}}{T_{1g}}} - e^{-\frac{T_{WL}}{T_{1g}}} \right) e^{-\frac{t}{T_{2g}}}$$

$$+ HI_o \phi_o \left(e^{-\frac{T_{WS1}}{T_{1o}}} - e^{-\frac{T_{WL}}{T_{1o}}} \right) e^{-\frac{t}{T_{2o}}} \qquad (A-6)$$

$$+ \sum_i P_w(T_2(i)) \left(e^{-\frac{T_{WS1}}{T_{1w}(i)}} - e^{-\frac{T_{WL}}{T_{1w}(i)}} \right) e^{-\frac{t}{T_{2(i)}}}$$

$$Edif2(t) = HI_g \phi_g \left(e^{-\frac{T_{WS2}}{T_{1g}}} - e^{-\frac{T_{WL}}{T_{1g}}} \right) e^{-\frac{t}{T_{2g}}}$$

$$+ HI_o \phi_o \left(e^{-\frac{T_{WS2}}{T_{1o}}} - e^{-\frac{T_{WL}}{T_{1o}}} \right) e^{-\frac{t}{T_{2o}}} \qquad (A-7)$$

$$+ \sum_i P_w(T_2(i)) \left(e^{-\frac{T_{WS2}}{T_{1w}(i)}} - e^{-\frac{T_{WL}}{T_{1w}(i)}} \right) e^{-\frac{t}{T_{2(i)}}}$$

When T_{WS1} is much larger than the maximum water T_1 value, then
contributions to Edif1 and Edif2 from under-polarized water become negligible
and the last term in Eqs. A-6 and A-7 disappears. The product of hydrogen index,
hydrocarbon porosity, and the differential polarization factor represents the
amplitude of the hydrocarbon signal. Thus, Eqs. A-6 and A-7 simplify to bi-
exponential equations

$$Edif1(t) = A_g(T_{WS1}, T_{WL}, T_{1g})e^{-\frac{t}{T_{2g}}}$$

(A-8)

$$+ A_o(T_{WS1}, T_{WL}, T_{1g})e^{-\frac{t}{T_{2o}}}$$

$$Edif2(t) = A_g(T_{WS2}, T_{WL}, T_{1g})e^{-\frac{t}{T_{2g}}}$$

(A-9)

$$+ A_o(T_{WS2}, T_{WL}, T_{1g})e^{-\frac{t}{T_{2o}}}$$

The hydrocarbon signal amplitudes in the Edif1 and Edif2 difference echo trains models can be obtained by applying matched-filter exponential fitting. Once the amplitudes have been determined for the two echo difference trains, the hydrocarbon T_1's can be calculated by taking their ratio. The hydrocarbon index and hydrocarbon porosity are canceled when the amplitude ratio is computed so that, for either hydrocarbon phase:

$$\frac{A_h(T_{WS1}, T_{WL}, T_{1h})}{A_h(T_{WS2}, T_{WL}, T_{1h})} = \frac{e^{-\frac{T_{WS1}}{T_{1h}}} - e^{-\frac{T_{WL}}{T_{1h}}}}{e^{-\frac{T_{WS2}}{T_{1h}}} - e^{-\frac{T_{WL}}{T_{1h}}}}$$

(A-10)

For the reader's convenience, a list of all notations used in the description above is given next.

Nomenclature

A	-	amplitude, p.u.
D	-	self-diffusion coefficient, cm^2/s
Edif1	-	echo train difference from T_{WL} and T_{WS1} data, p.u.
Edif2	-	echo train difference from T_{WL} and T_{WS2} data, p.u.
F	-	contour constant
HI	-	hydrogen index
P	-	incremental porosity
t	-	time, s
T_1	-	longitudinal NMR relaxation time, s
T_2	-	transverse NMR relaxation time, s
T_e	-	echo spacing, ms
T_w	-	wait-time, s
T_{WL}	-	long wait time in the triple-wait-time method, s
T_{WS1}	-	shortest wait time in the triple-wait-time method, s
T_{WS2}	-	second shortest wait time in the triple-wait-time method, s
ϕ	-	porosity

Subscripts

bvi	-	capillary-bound water
cbw	-	clay-bound water
g	-	gas
h	-	hydrocarbon
mp	-	most probable
o	-	oil
p1	-	fluid phase one
p2	-	fluid phase two
pw	-	producible water
t	-	total

ta   -   total apparent

w   -   water

While the invention has been described with reference to a preferred
embodiment, it will be appreciated by those of ordinary skill in the art that
modifications can be made to the structure and form of the invention without
departing from its spirit and scope which is defined in the following claims.

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What is claimed is:

1. A nuclear magnetic resonance (NMR) data acquisition method,
comprising:

providing a first set of CPMG pulses associated with a first relatively
short recovery time T_{WS1};

providing a second set of CPMG pulses associated with a second
relatively short recovery time T_{WS2}, where T_{WS2} is longer than T_{WS1};

providing a third set of CPMG pulses associated with a relatively long
recovery time T_{WL1};

receiving NMR echo signals from a population of particles in response to
the first, second and third sets of CPMG pulses; and

processing the received NMR echo signals to provide a data
representation associated with the longitudinal relaxation time constant T_1 of the
population of particles.

2. The method of claim 1 wherein the steps of providing the first, second
and third sets of CPMG pulses are interleaved in time.

3. The method of claim 1 wherein NMR echo signals received from at
least two of the first, second and third sets of CPMG pulses are acquired in
different sensitive volumes.

4. The method of claim 1 wherein the NMR echo signals received from
the first set of CPMG pulses are partially recovered.

5. The method of claim 1 wherein the steps of providing the first, second
and third sets of CPMG pulses are performed using a multi-frequency NMR
logging tool.

6. The method of claim 1 wherein the first and the second sets of CPMG
pulses have different operating frequencies.

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7. The method of claim 1 further comprising the step of providing a fourth set of CPMG pulses associated with a second relatively long recovery time T_{WL2}.

8. The method of claim 7 wherein the third and the fourth sets of CPMG pulses have different operating frequencies.

5

9. The method of claim 7 wherein at least one set of CPMG pulses associated with a relatively short recovery time and at least one set of CPMG pulses associated with a relatively long recovery time have the same operating frequency.

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10. The method of claim 1 wherein for at least one of the first, second and third sets of CPMG pulses one or more corresponding sets of CPMG pulses with the same recovery time are provided at a different operating frequency.

11. The method of claim 1 wherein the first and second relatively short recovery times T_{WS1} and T_{WS2} are selected long enough to substantially polarize a

15 water phase component in the population of particles.

12. The method of claim 1 wherein the recovery times T_{WS1}, T_{WS2} and T_{WL1} of the first, second and third sets of CPMG pulses are selected such that water-phase contribution is substantially canceled in a difference signal formed by subtracting NMR signals corresponding to a relatively short recovery time

20 from NMR signals corresponding to the relatively long recovery time T_{WL1}.

13. The method of claim 1 wherein the first, second and third sets of CPMG pulses are applied in three different frequency bands.

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14. A method for conducting NMR logging measurements, comprising:

providing a data acquisition sequence comprising at least two sets of CPMG pulses having relatively short recovery times T_{WS1} and T_{WS2}, respectively, and at least one set of CPMG pulses having relatively long recovery time T_{WL1};

5   receiving NMR echo signals from a population of particles in a geologic formation in response to the provided sets of CPMG pulses;

processing the received NMR echo signals to determine a first and a second apparent volumes for at least one hydrocarbon fluid phase of the geologic formation, said first apparent volume being determined from a data representation associated with signals having short recovery time T_{WS1}, and the second apparent

10   volume being determined from a data representation associated with signals having short recovery time T_{WS2};

providing a data representation associated with the longitudinal relaxation time constant T_1 of said at least one hydrocarbon fluid phase based on the

15   determined first and second apparent volumes.

15. The method of claim 14 wherein the step of processing the received NMR echo signals comprises:

forming a first difference signal Edif1 by subtracting NMR signals having relatively short recovery time T_{WS1} from NMR echo signals having relatively long

20   recovery time T_{WL}.

16. The method of claim 15 further comprising the step of computing T_2 distribution of the first difference signal Edif1.

17. The method of claim 16 further comprising determining a value for

25   the T_2 relaxation time of said at least one hydrocarbon phase.

18. The method of claim 17 wherein the value for the T_2 relaxation time is determined as the most probable value based on the T_2 distribution of the first difference signal Edif1.

19. The method of claim 17 further comprising the step of:

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forming a second difference signal Edif2 by subtracting NMR signals having relatively short recovery time T_{WS2} from NMR echo signals having relatively long recovery time T_{WL}.

20. The method of claim 19 wherein the step of determining a first and second apparent volumes for said at least one hydrocarbon phase are based on the

5   determined value for the T_2 relaxation time and the first and second difference signals Edif1 and Edif2.

21. The method of claim 20 wherein the step of determining said first and second apparent volumes is performed using matched filters to fit a model of the signal to each difference signal Edif1 and Edif2.

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22. The method of claim 20 wherein the step of determining a first and second apparent volumes for said at least one hydrocarbon phase trains is performed by fitting the equation:

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$$A(t) = A_o e^{-\frac{t}{T_{2mp}}},$$

where A(t) represents the average echo difference amplitude Edif1 and Edif2 at echo time t and T_{2mp} is the most probable amplitude T_2 value for the hydrocarbon

20   phase.

23. The method of claim 20 wherein the step of providing a data representation associated with the longitudinal relaxation time constant T_1 comprises: for each of said at least one hydrocarbon fluid phase solving the following equation for the corresponding $T_{1,pi}$ parameter:

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$$\frac{e^{-\frac{T_{WS1}}{T_{1,pi}}} - e^{-\frac{T_{WL}}{T_{1,pi}}}}{e^{-\frac{T_{WS2}}{T_{1,pi}}} - e^{-\frac{T_{WL}}{T_{1,pi}}}} = \frac{A(T_{WS1}, T_{WL}, T_{1,pi})}{A(T_{WS2}, T_{WL}, T_{1,pi})}$$

30

where $A(T_{WS1}, T_{WL}, T_{1,pi})$ represents the apparent hydrocarbon amplitude of the ith hydrocarbon phase from Edif1, and $A(T_{WS2}, T_{WL}, T_{1,pi})$ is the apparent hydrocarbon amplitude of the ith hydrocarbon phase from Edif2.

24. The method of claim 23 further comprising the step of computing corrected hydrocarbon volumes based on the computed value for the corresponding T_1 parameter of said at least one hydrocarbon fluid phase.

25. The method of claim 24, wherein the corrected volumes are computed using the equation:

$$\phi_i = \frac{A_{o,Edif1}}{HI_i \left(e^{-\frac{T_{WS1}}{T_{1,mp}}} - e^{-\frac{T_{WL}}{T_{1,mp}}} \right)},$$

where HI_i is the hydrogen index for the ith hydrocarbon phase.

26. The method of claim 14 further comprising the step of computing the total apparent porosity ϕ_{ta} of the geologic formation.

27. The method of claim 26 further comprising the step of determining the total porosity of the formation ϕ_t from the total apparent porosity ϕ_{ta} and apparent volume corrections computed based on the provided data representation associated with the longitudinal time constant(s) T_1 of the fluid phases.

28. The method of claim 27 further comprising the step of determining the total water volume as the difference between the total porosity and porosity associated with hydrocarbon phases.

29. A method of operating a multi-volume NMR logging tool, comprising:

(a) acquiring a first NMR echo train or sets of echo trains in a first sensitive volume of the tool, said first echo train(s) carrying information about NMR signals with recovery time T_{WS1};

(b) acquiring a second NMR echo train or sets of echo trains in a second sensitive volume of the tool, said second echo train(s) carrying information about NMR signals and having recovery time T_{WL};

(c) acquiring a third NMR echo train or sets of echo trains, said third echo train(s) carrying information about NMR signals with recovery time T_{WS2};

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(d) computing values for the transverse relaxation time T_2 and apparent volume for at least one hydrocarbon fluid phase based on the acquired NMR echo trains; and

(e) providing a data representation associated with the longitudinal relaxation time constant T_1 of said at least one hydrocarbon fluid phase based on

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the determined first and second apparent volumes.

30. A nuclear magnetic resonance (NMR) data processing method for use in borehole logging, comprising:

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selecting values for a second relatively short recovery time T_{WS2} using a known functional relationship based on estimates of: (a) a first relatively short recovery time T_{WS1} needed to polarize water signals in a geologic formation surrounding the borehole; and (b) expected T_1 values for hydrocarbon fluid phases in the geologic formation surrounding the borehole;

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providing a data acquisition sequence comprising at least two sets of CPMG pulses having said relatively short recovery times T_{WS1} and T_{WS2}, respectively, and at least one set of CPMG pulses having relatively long recovery time T_{WL};

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processing NMR echo signals received in response to the data acquisition sequence to provide an estimate of the true values for the longitudinal relaxation time constant T_1 of hydrocarbon fluid phases in the geologic formation, wherein the accuracy of the estimates of the T_1 constant is controlled in the step of selecting.

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processing the received NMR echo signals to provide a data representation associated with the longitudinal relaxation time constant T_1 of the population of particles.

31. The method of claim 30, wherein the known functional relationship is of the form:

5

$$F = \left[e^{-(T_{WS1}/T_1)} - e^{-(T_{WL}/T_1)} \right] \Big/ \left[e^{-(T_{WS2}/T_1)} - e^{-(T_{WL}/T_1)} \right]$$

where F is a constant.

10   32. The method of claim 31 wherein the value of the constant F is selected greater than about 1.4.

33. The method of claim 31 wherein the value of the constant F is selected in the range between about 1.4 and 5.

34. The method of claim 31 wherein the functional relationship is

15   expressed as T_{WS1} - T_{WS2} cross-plots for select values of the expected T_1 constant and the T_{WL} relaxation time.

35. The method of claim 31 wherein the functional relationship is programmed in a computer memory and the step of selecting is performed automatically based on the values of the expected T_1 constant and the T_{WL}

20   relaxation time.

36. A computer software product for implementing the steps of the method of claim 30 on a computer controlling the operation of a NMR logging tool.
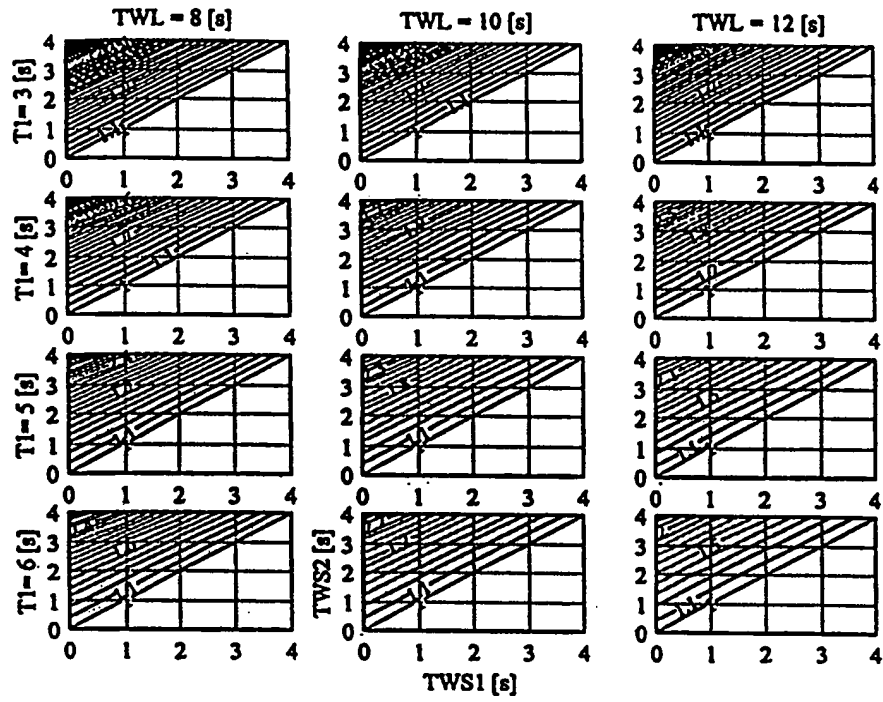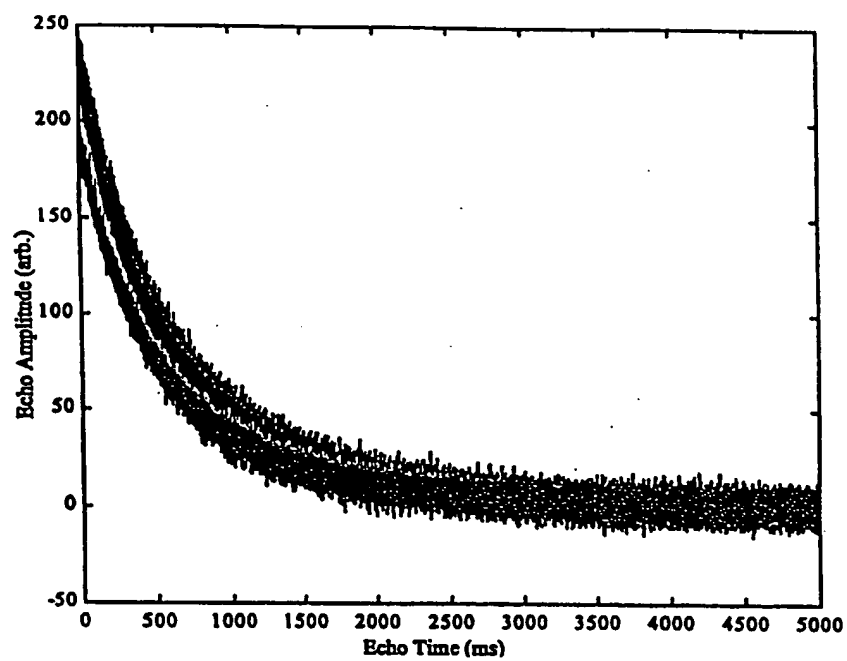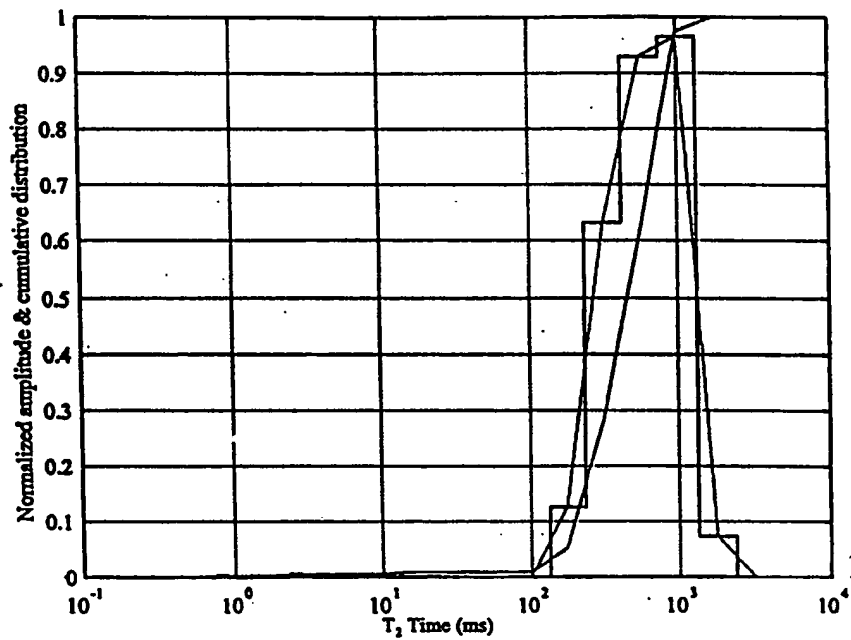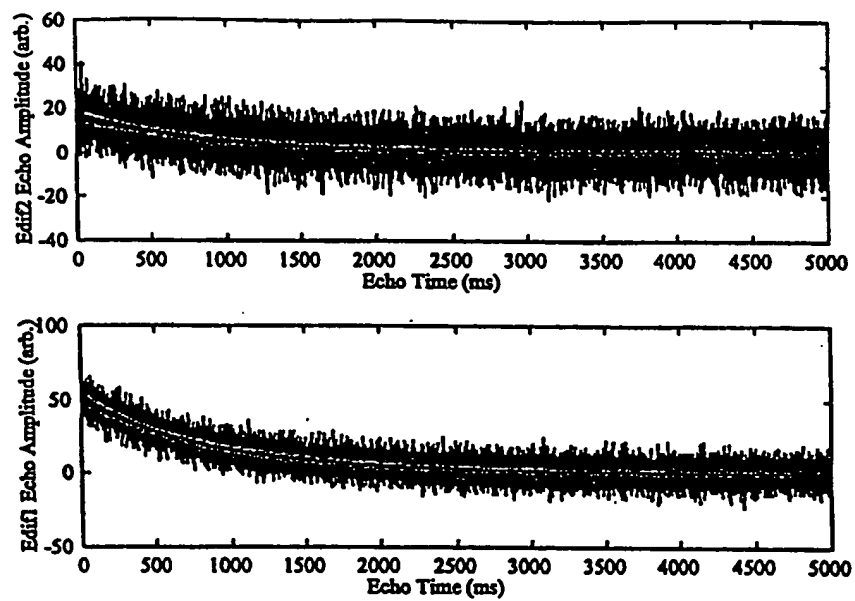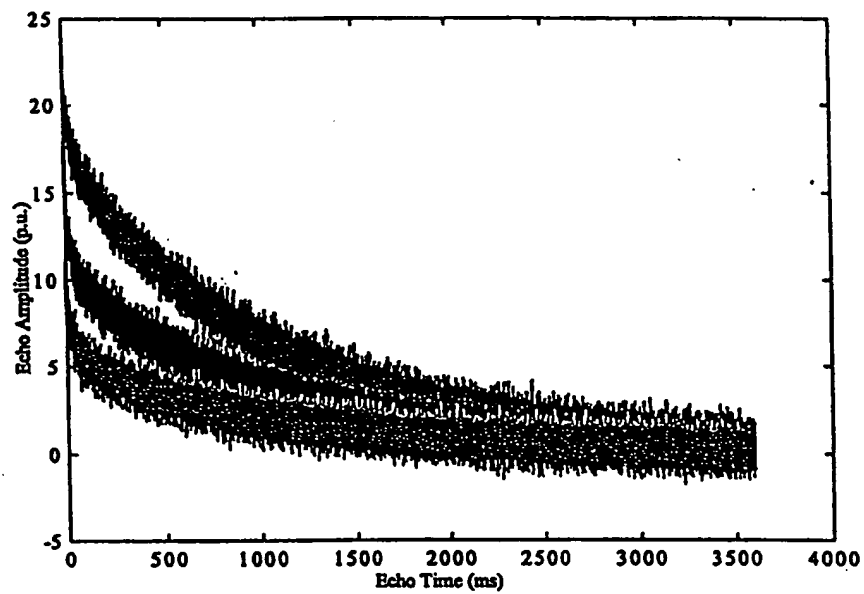
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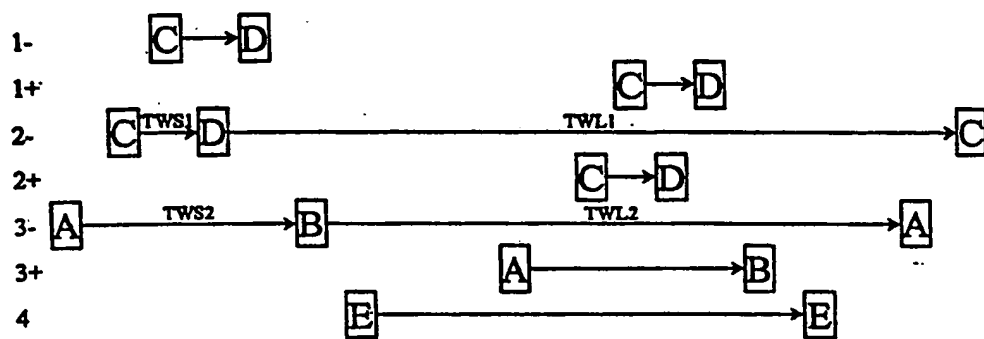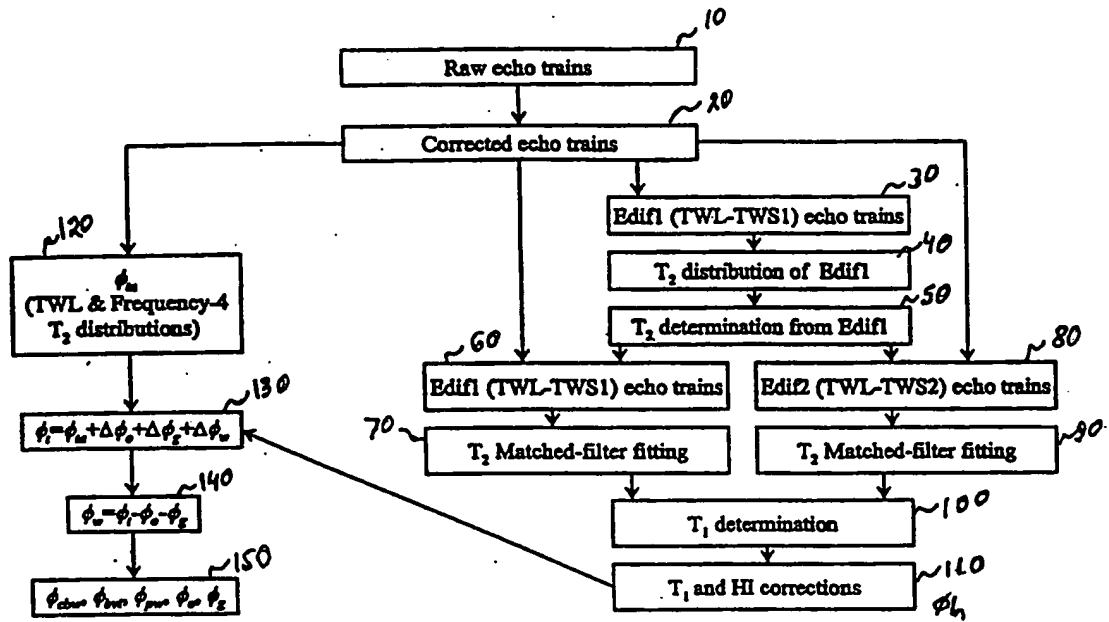
Fig. 1

Fig. 2
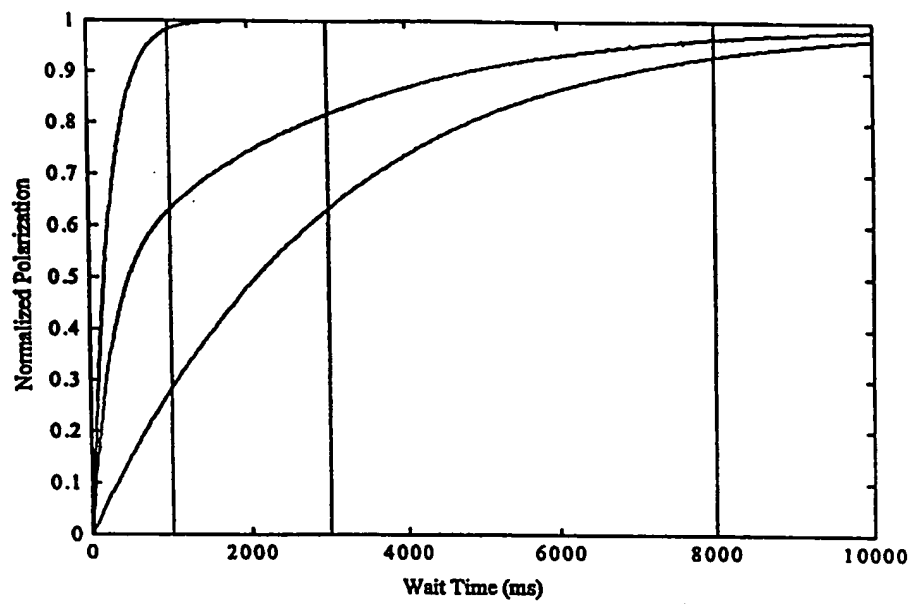
Fig. 3

Fig. 4

Fig. 5

Fig. 6

Fig. 7

Fig. 8
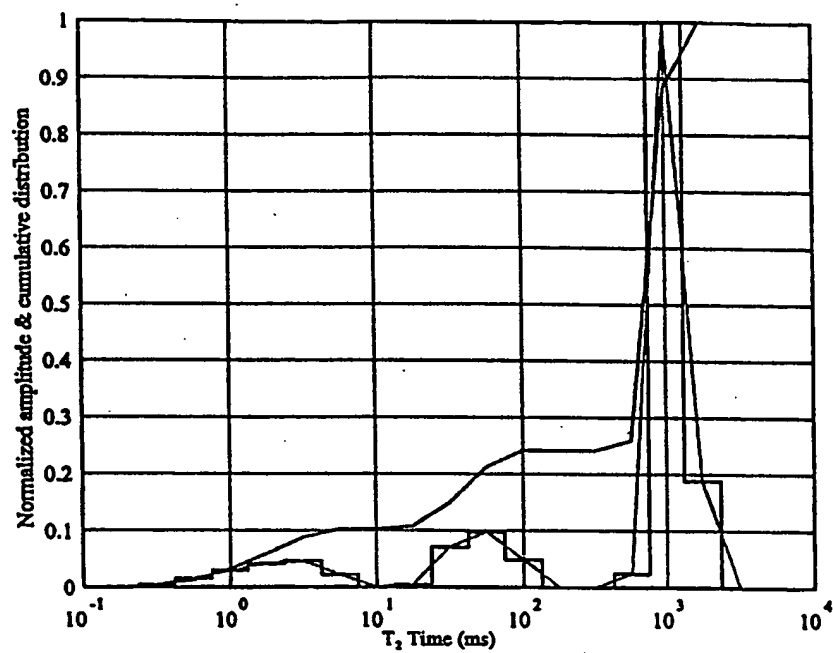
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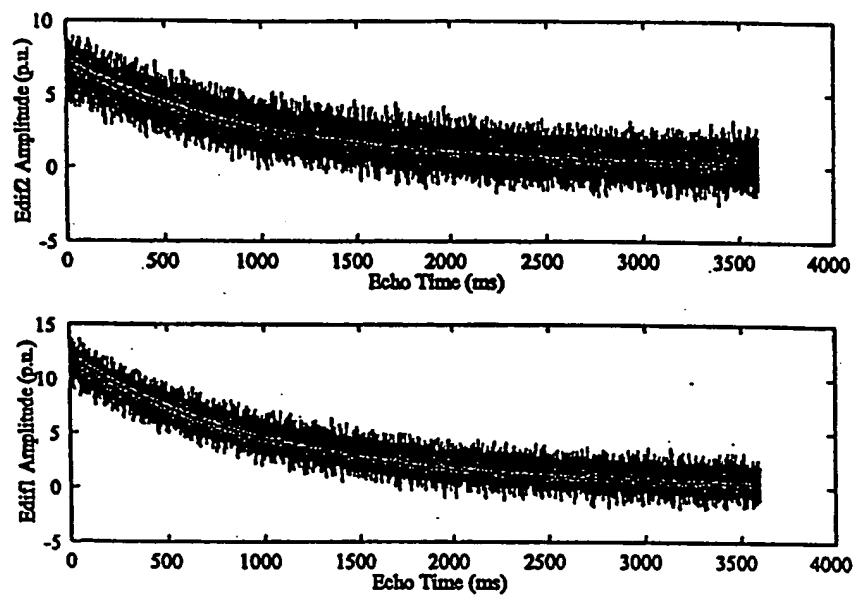
Fig. 10
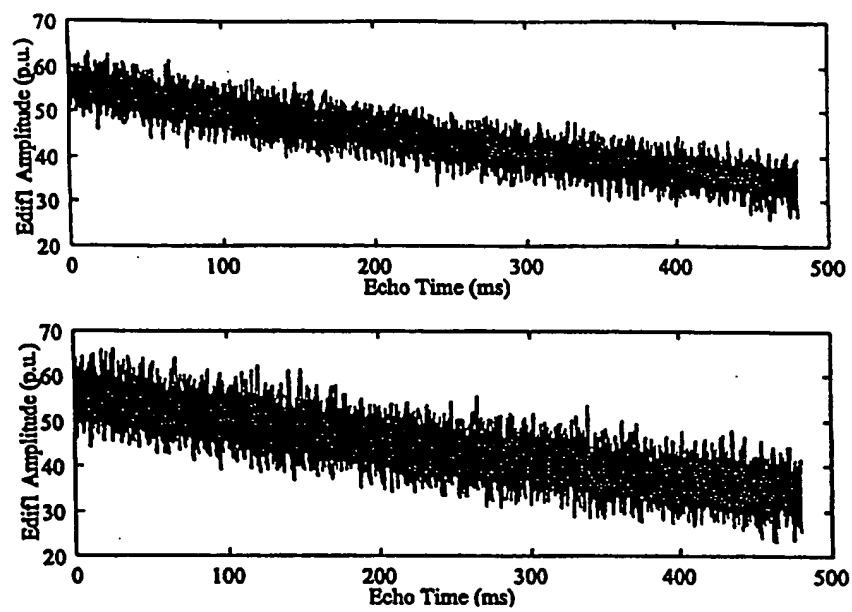
Fig. 11
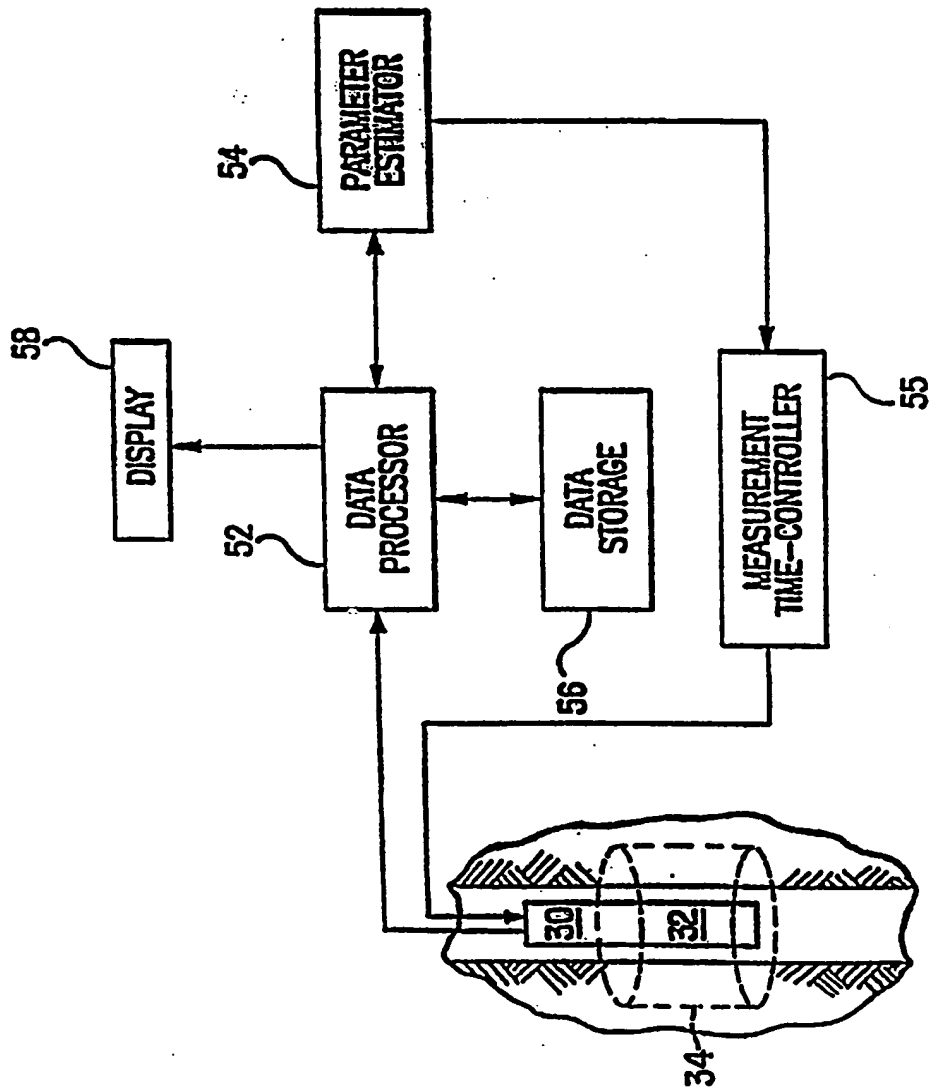
FIG. 12

INTERNATIONAL SEARCH REPORT

A.   CLASSIFICATION OF SUBJECT MATTER
IPC(7)   :   G01V 3/00
US CL   :   324/303
According to International Patent Classification (IPC) or to both national classification and IPC

B.   FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)
U.S. : 324/303, 300, 306, 307, 309, 314

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)
EAST

C.   DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 5,023,551 A (KLEINBERG et al) 11 June 1991 (11.06.1991), col 18, lines 22-68, col 19, lines 1-4.	1-36
A,P	US 6,049,205 A (TAICHER et al) 11 April 2000 (11.04.2000), see Fig. 2 and Fig.3 and the abstract of the disclosure.	1-36

☐ Further documents are listed in the continuation of Box C.   ☐ See patent family annex.

*	Special categories of cited documents:	"T"	later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention
"A"	document defining the general state of the art which is not considered to be of particular relevance		
"E"	earlier application or patent published on or after the international filing date	"X"	document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone
"L"	document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)	"Y"	document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art
"O"	document referring to an oral disclosure, use, exhibition or other means		
"P"	document published prior to the international filing date but later than the priority date claimed	"&"	document member of the same patent family

Date of the actual completion of the international search	Date of mailing of the international search report
28 September 2000 (28.09.2000)	21 DEC 2000
Name and mailing address of the ISA/US	Authorized officer
Commissioner of Patents and Trademarks Box PCT Washington, D.C. 20231	Louis Arana
Facsimile No. (703)305-3230	Telephone No. (703) 305-4913

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